Thunder Energy Inc.

location

1996

location

1997

location

1998

location

1999 Annual Review

location

2000

Location means everything. Being in the right place at the right time – and having strategies in place to add value and drive profitability. At Thunder, location means the pieces are in place for excellent and profitable growth.

150 locations in our drilling inventory

4 Thunder-operated core areas

65 percent weighting to natural gas

\$5.03 per boe average finding costs for total reserves since inception

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Highlights

Financial

Years ended December 31 ($ thousands, except where noted)	1999	1998	% Change
Petroleum and natural gas sales	$ 15,431	$ 10,013	54
Cash flow from operations	$ 7,785	$ 4,537	72
Per share – basic *($)*	$ 0.35	$ 0.28	25
– fully diluted *($)*	$ 0.33	$ 0.25	32
Net income	$ 2,437	$ 1,314	85
Per share – basic *($)*	$ 0.11	$ 0.08	38
– fully diluted *($)*	$ 0.10	$ 0.08	25
Return on equity *(%)*	10.5	8.6	22
Capital expenditures	$ 21,891	$ 13,236	65
As at December 31			
Working capital deficit	$ 5,108	$ 3,951	29
Long-term debt	$ 11,825	$ 9,754	21
Shareholders' equity	$ 29,342	$ 16,968	73
Total assets	$ 51,813	$ 33,554	54
Common shares outstanding *(thousands)*			
Basic	25,744	19,279	34
Fully diluted	27,544	21,744	27
Weighted average – basic	21,966	16,187	36
– fully diluted	24,408	18,903	29
Share price *($)*			
High	$ 2.65	$ 2.44	9
Low	$ 1.00	$ 1.25	(20)
Close	$ 2.00	$ 1.60	25

Operations

Years ended December 31	1999	1998	% Change
Average daily production			
Natural gas *(mcf)*	9,347	7,748	21
Crude oil and NGLs *(bbls)*	761	853	(11)
Barrels of oil equivalent *(boe)*	1,696	1,628	4
Average product prices			
Natural gas *($/mcf)*	$ 2.66	$ 2.00	33
Crude oil and NGLs *($/bbl)*	$ 22.94	$ 14.57	57
Wells drilled			
Gross	28.0	33.0	(15)
Net	15.4	16.5	(6)
Success rate *(%)*	93	91	2
As at December 31			
Reserves – proved plus probable			
Natural gas *(bcf)*	64.2	45.2	42
Crude oil and NGLs *(mbbls)*	3,852	3,548	9
Barrels of oil equivalent *(mboe)*	10,272	8,068	27
Net asset value *($ thousands)*	$ 68,810	$ 47,341	45
Per share – basic *($)*	$ 2.58	$ 2.29	13
– fully diluted *($)*	$ 2.50	$ 2.17	15

In 1999, we prepared for an oil price upswing by expanding our opportunity base – adding land, a new core area and creating a large inventory of drilling locations. We have since completed a partial buyout of our joint venture partner. These investments should generate a 60% production increase in the second quarter over year-end 1999, and will continue to drive steady, profitable growth.

Positioned for Growth

1999 Review

Douglas A. Dafoe
President &
Chief Executive Officer

Thunder's strategies:

- *Operate core areas where we have the expertise and infrastructure to add gas-weighted production and reserves.*
- *Continually expand our land in core areas to maintain a dominant position.*
- *Concentrate on drilling of medium-risk, multi-zone plays.*
- *Control infrastructure and have available capacity for bringing wells onstream in 30 to 60 days.*
- *Continue to evaluate and expand into properties that fit our operational criteria.*

As 1999 closed, we again reached new benchmarks for cash flow and earnings. Yet the year's most telling feature was the strength of our strategies in both the lows – and highs – of oil prices. Through prudent investments, our production has already grown substantially in 2000 setting the stage for new milestones in our operating and financial results. That achievement resulted from the groundwork laid in 1999.

We faced two very different operating environments last year. Low oil prices hung over the industry for the first six months, but then began to rally, eventually reaching highs not seen in a decade. In both scenarios, we stuck to our core strategies and captured tremendous growth opportunities. For second quarter 2000, our production is expected to average 3,200 boe/d, up 60% over year-end 1999.

In the first half of the year, we concentrated on expanding our opportunity base in preparation for an oil price recovery. To preserve capital, we deferred most of our drilling, which led to a flat production profile in the first half of 1999. Yet we expanded our land position in core areas, continued to develop a large drilling inventory and pursued facility expansions to bring new gas volumes onstream. We also added a fourth core area at Fenn/Big Valley, which is very much a Thunder-style property. We operate, control infrastructure, have a dominant land position and a good understanding of the multi-zone plays.

As oil prices strengthened into the third quarter, we reactivated drilling and conducted our most active program ever, funded by a flow-through share issue in October that raised $3.9 million. The result was very profitable production and reserve additions. Our four-year finding and development costs for total reserves now average $5.03/boe. In today's commodity price environment, with operating netbacks in excess of $20.00/boe, that translates into a 4:1 return on our investments.

Based on our track record of low cost growth in core areas, we began work on a deal in late 1999 to substantially grow the company. Through two separate transactions after year end, we increased our interests to 75% from 50% in three Thunder-operated properties – Rosalind, Matziwin and Manola. To date in 2000 we have acquired a total of 915 boe/d for a purchase price of $25.3 million, a very prudent investment considering we acquired proved reserves for $6.38/boe.

This transaction has increased our bank debt for 2000, but to reduce risk we have entered into a hedging program that will guarantee a portion of our cash flow for the year. We have locked in 65% of our current production guaranteeing an operating netback of $23.00/boe until the end of the year. This added stability to our cash flow will enable Thunder to reduce long-term debt by $6 million by year end and, even in a lower price commodity environment, will maintain our debt at or below 2.0 times cash flow. At the same time, we will have the financial flexibility to fund an active drilling program in 2000 which is expected to continue to add low cost reserves and production that will drive our profitability.

This is an exciting time for Thunder and our prospects have never been better. We are on the verge of reaching a major milestone of 5,000 boe/d within the next one to two years.

We would like to thank our dedicated staff who's efforts drive our success, and our shareholders for their continued support.

On Behalf of the Board,

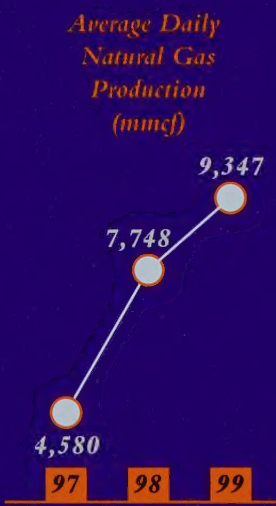
Douglas A. Dafoe
President and Chief Executive Officer
April 6, 2000

Our drilling success has been in excess of 90% since the company was formed in 1996. This high rate centres around the considerable knowledge we have gained about our core areas, which all share similar geology. The multi-stacking zones reduce our risk, as does our focus on shallow to medium depth drilling.

Positioned for Growth

Exploration and Development

David L. Barlow
Vice President,
Exploration



Thunder's steady growth has been based on consistent operating strategies. We operate core areas, control infrastructure and work to add value through internally-generated exploration and development. This operational template has proven to generate excellent results. As part of an ongoing measurement of performance in the company, we thoroughly analyzed our drilling program since the company's inception in 1996. These historical results illustrate how our strategies have added value in core areas – and our profitability in adding production and reserves. The results also provide some indication of our future growth potential and the value of our large drilling inventory.

Past results guide the future

Thunder recently conducted an internal study of all of the 90 wells drilled, both successful and unsuccessful, since the company's inception. Finding and development costs ranged from $5.00/boe to $9.00/boe depending on the type of play. This study was based on the 1999 year-end reserve report using proved reserves. On average, results from the drilling program yielded a recycle ratio of 4:1 based on today's commodity price environment. Since we began drilling wells in late 1996, we have achieved proved reserves of 100,000 boe per well and average productivity of 80 boe/d. The results are summarized below:

Historical Drilling Results 1996–1999

Play type	Number of wells drilled	Depth *(metres)*	Average Reserves	Capital Costs *($)*	Finding & Development Costs *($/boe)*
Mannville gas	50	1,000 – 1,200	1 bcf	500,000	5.00
Mannville oil	10	1,000 – 1,200	60,000 bbls, 0.4 bcf	525,000	5.25
Horizontal oil	18	1,100	140,000 bbls	740,000	5.28
Shallow gas	12	350 – 500	0.35 bcf	315,000	9.00

Current drilling inventory

Based on the data from our historical results, we have analyzed the potential of our current drilling inventory. The following table summarizes this analysis, indicating the significant growth potential of our existing asset base.

Drilling Inventory Analysis

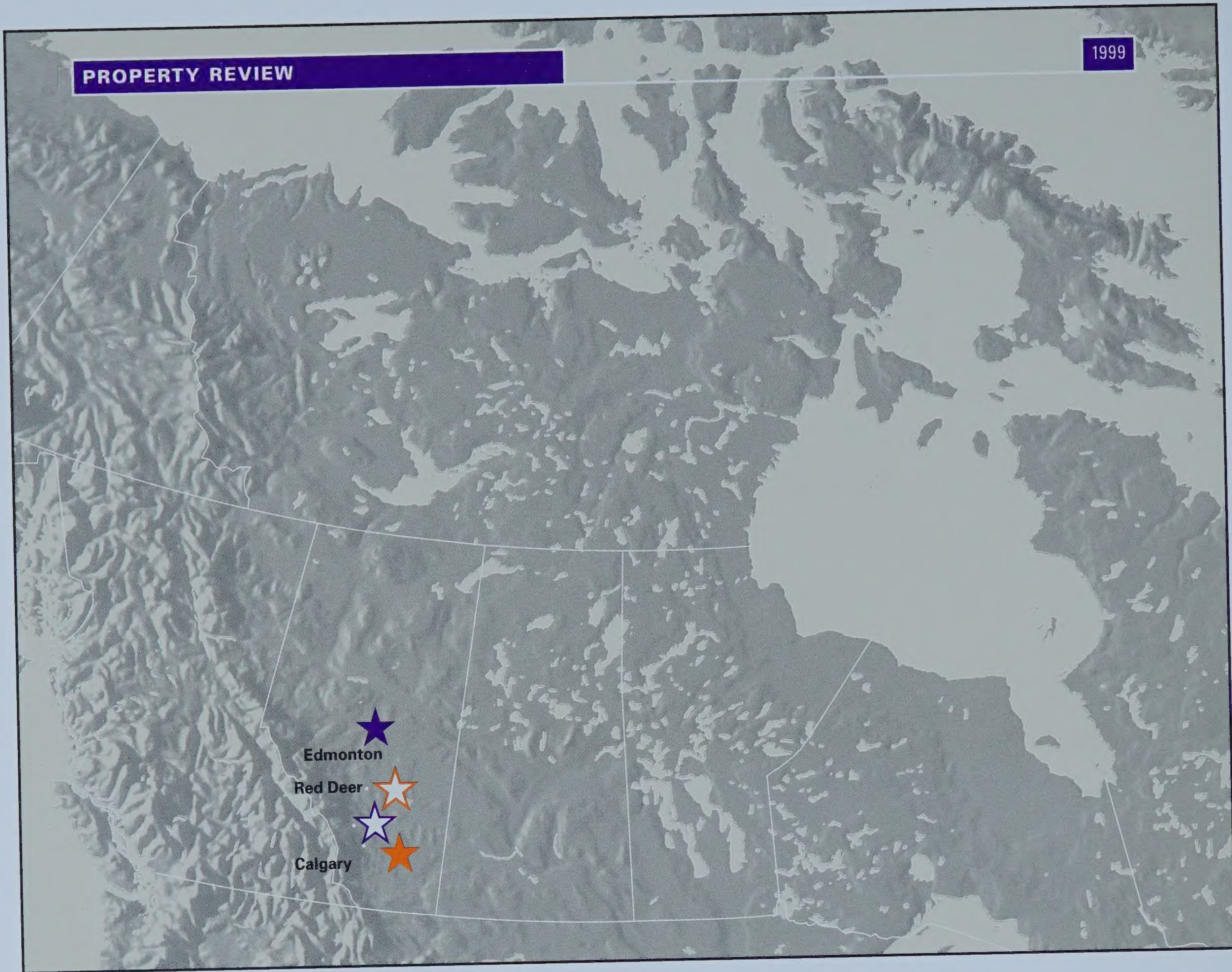
Play type	Firm Locations	Expected Locations(1)	Potential Reserves(2)
Mannville gas	41	35	50 bcf
Mannville oil	10	12	800 mbbls, 6 bcf
Horizontal oil(3)	6	20	1.2 mmbbls
Shallow gas	23	17	10 bcf
Total	80	84	66 bcf, 2 mmbbls

Notes:

1. Expected locations are prospects in which Thunder holds the land but has not yet finalized a drilling location. Seventy-five percent of these locations have been included in the potential reserve calculation.

2. Calculated using Thunder's net working interest updated for acquisition of partner's interest.

3. Horizontal oil was calculated using a reduced 75 mbbls per well, which is the expectation from our second oil pool at Rosalind.



An estimated 40% of gas reserves* remaining to be found in Western Canada are expected to come from shallow to medium depth geological zones. These plays are the backbone of Thunder's core areas. Thunder primarily pursues gas plays, but the multi-zone potential in the area has yielded significant oil production and reserve additions.

* *Natural Gas Potential in Canada, A Report by the Canadian Gas Potential Committee, Affiliated with the Department of Geology and Geophysics, University of Calgary, 1997*

Rosalind

Rosalind remains the company's largest source of both oil and natural gas, and further growth is planned in 2000. Thunder's Mannville oil pool discovery in late 1997 is continuing to be developed, along with a second oil pool discovered in late 1998. A third pool has been evaluated on 3D seismic, with drilling plans pending.

In the first half of 1999, horizontal oil drilling was deferred. In June 1999, we reactivated our horizontal program and drilling will continue into 2000. Multi-zone gas targets will be pursued including a number of Mannville tests and shallower Belly River wells. In 1999, Thunder installed acid gas injection facilities to increase sour gas processing.

Manola

Manola is primarily a gas play with the added advantage that volumes are sold to a local utility at a premium to spot market prices. The area is largely unexplored, as, until last fall, there was a lack of processing facilities. New pipeline capacity has been added and a mid-stream operator completed a 10 mmcf/d gas facility in October. This plant is currently dedicated to Thunder.

Previously shut-in gas wells plus new wells drilled during 1999 have been brought onstream resulting in current production in excess of 8.0 mmcf/d. Thunder has a huge inventory of exploration and development wells to choose from in 2000, including development of existing pools. Production from these new wells is expected to fill the plant, however, the facility operator has the ability to expand capacity.

Matziwin

Thunder has an operated interest in 78 sections of land at Matziwin. This area has consistently provided Thunder with multi-zone oil and gas prospects. Capacity is currently available, and drilling is expected to generate substantial growth in 2000.

Three gas wells currently awaiting pipeline construction should be tied in by mid-year. Other plans for the year include expansion of the exploration block in the south, and Thunder is pursuing downspacing of existing oil pools.

Fenn/Big Valley

Thunder acquired this new core area in 1999 and gained operatorship of 45 sections of land and control of a 10 mmcf/d plant with considerable available capacity. Successful drilling in 1999 doubled production to 550 boe/d and further increases will be seen in 2000. Thunder will drill a number of shallow gas plays and prolific deeper Mannville exploration targets.

Motivated by the success of our operational template, we increased our interests in three of our core areas in the first quarter of 2000. This will allow us to reap greater rewards from our drilling programs. We will continue to focus on our operated core areas and pursue new areas where we can have a dominant land position and control infrastructure to streamline drilling and development of the resource base.

Positioned for Growth

Operations Review

Terry S. Meek
Vice President,
Engineering

Land holdings

In 1999, Thunder spent $3.6 million on land acquisition costs, the largest annual amount spent to date. Of the total, $2.8 million was Thunder's share of a joint venture exploration fund initiated in 1998. With the higher level of spending on land and seismic in 1998/1999, Thunder has established significant blocks of undeveloped land in its core areas. This has enabled the company to develop a drilling inventory in excess of 150 locations in its core areas.

Land Holdings	Developed Acres		Undeveloped Acres		Total Acres	
As at December 31, 1999	Gross	Net	Gross	Net	Gross	Net
Rosalind	53,267	20,259	44,216	18,855	97,483	39,114
Manola	8,960	3,488	57,280	27,673	66,240	31,161
Fenn/Big Valley	21,220	18,452	9,839	8,673	31,059	27,125
Matziwin	20,794	7,845	29,220	13,343	50,014	21,188
Other	–	–	12,787	6,225	12,787	6,225
Total	104,241	50,044	153,342	74,769	257,583	124,813

Continued drilling success

During 1999, the company participated in 28 wells, all operated by Thunder. Ten wells were drilled at Rosalind, seven at Manola, six at Matziwin and three at Fenn/Big Valley. Total net reserve additions from the drill bit amounted to 363 mbbls and 9.3 bcf in 1999.

Drilling Activity	**1999**		1998	
Year ended December 31	Gross	Net	Gross	Net
Gas	**14**	**7.8**	22	11.0
Oil	**11**	**5.8**	8	4.0
Service	**1**	**0.5**	–	–
Dry	**2**	**1.3**	3	1.5
Total	**28**	**15.4**	33	16.5
Success rate *(%)*	**93**		91	
Average working interest *(%)*	**55**		50	

Producing Property Summary			Barrels of
Year ended December 31, 1999	Oil & NGLs	Natural Gas	Oil Equivalent
	(bbls/d)	*(mcf/d)*	*(boe/d)*
Rosalind	560	4,715	1,032
Matziwin	81	2,060	287
Manola	94	914	186
Fenn/Big Valley[1]	26	1,658	191
Total	761	9,347	1,696

(1) Represents production from May 1, 1999.

Reserve growth

Net reserves grew by 28% during the year to 10.3 million barrels of oil equivalent. Additions from drilling and acquisitions totaled 2.9 million barrels of oil equivalent, split 55% to acquisitions and 45% to drilling. Most of the acquisition additions were from the Fenn/Big Valley core property acquisition. Proved undeveloped oil reserves represent infill locations for Thunder's horizontal oil pools at Rosalind. Proved undeveloped gas and proved non-producing gas reserves are principally second zones behind pipe of existing producers.

Reserves	Remaining Reserves		Future Cash Flow Before Income Tax Undiscounted	Discounted	
	Natural Gas	Crude Oil & NGLs		at 10%	at 15%
	(bcf)	*(mbbls)*	*($000)*	*($000)*	*($000)*
Proved developed					
Producing	30.1	1,776	72,485	50,533	44,471
Non-producing	10.2	83	18,835	5,210	3,458
Proved undeveloped	12.2	1,284	30,825	17,041	13,821
Total proved	52.5	3,143	122,145	72,784	61,750
Probable additional	11.7	709	25,727	9,743	7,172
Total	**64.2**	**3,852**	**147,872**	**82,527**	**68,922**

As at January 1, 2000 determined by Sproule Associates Limited, independent consultants, using escalated prices and costs as at March 1, 2000.

Reconciliation of Reserves	Gas *(bcf)* Proved	Probable	Total	Crude Oil *(mbbls)* Proved	Probable	Total	Boe *(mboe)* Total
January 1, 1999	39.4	5.8	45.2	2,595	953	3,548	8,068
Drilling	8.1	1.2	9.3	363	–	363	1,293
Acquisitions	7.3	6.0	13.3	173	98	271	1,601
Production	(3.4)	–	(3.4)	(279)	–	(279)	(619)
Revisions to prior estimates	1.2	(1.4)	(0.2)	292	(343)	(51)	(71)
January 1, 2000	**52.6**	**11.6**	**64.2**	**3,144**	**708**	**3,852**	**10,272**

Net Asset Value *($ thousands, except per share amounts)*	1999	1998	1997
Reserves discounted at 10% pre-tax(1)	**$ 77,655**	$ 54,860	$ 48,270
Undeveloped land(2)	**5,608**	2,966	1,463
Working capital deficiency	**(5,108)**	(3,951)	(6,792)
Bank debt	**(11,825)**	(9,754)	(6,962)
Net asset value – basic	**66,330**	44,121	35,979
Proceeds of share purchase warrants and stock options	**2,480**	3,220	2,634
Net asset value – fully diluted	**$ 68,810**	$ 47,341	$ 38,613
Per share amounts			
Basic	**$ 2.58**	$ 2.29	$ 2.50
Fully diluted	**$ 2.50**	$ 2.17	$ 2.31

(1) Probable reserves have been risked at 50%.
(2) Undeveloped land is valued at $75 per acre.

Finding and development costs

Thunder's 1999 finding and development costs were higher than the company's first quartile performance in previous years. A large contributor to the increase was the Fenn/Big Valley acquisition, which equated to $9.28 for proved reserves, and $5.28 for proved plus probable. Thunder also spent a larger amount on land and seismic than in previous years. Land and seismic costs equated to an estimated $1.20 per proved boe compared with $0.20 per proved boe in previous years. The 1999 costs for acquisitions, land and seismic will greatly benefit Thunder in future years as it drills its large inventory of wells.

Finding and Development Costs *($ thousands, except where noted)*	12/31/99	12/31/98	12/31/97	Inception to date
Finding and development costs				
Land and seismic	**$ 4,305**	$ 582	$ 1,311	$ 6,423
Drilling and completions	**6,642**	5,949	6,243	19,364
Acquisitions	**8,408**	2,843	6,923	22,113
Equipment and facilities	**2,503**	3,825	4,709	11,553
Total finding costs	**$ 21,858**	$ 13,199	$ 19,186	$ 59,453
Reserve additions				
Proved				
Gas *(mmcf)*	**16,635**	10,300	24,700	61,030
Oil *(mbbls)*	**828**	1,264	1,684	3,832
Boe *(mboe)*	**2,492**	2,294	4,154	14,004
Probable				
Gas *(mmcf)*	**5,886**	100	4,200	11,686
Oil *(mbbls)*	**(244)**	134	780	710
Boe *(mboe)*	**346**	144	1,200	2,658
Costs per boe 10.1 conversion				
Proved	**$ 8.75**	$ 5.75	$ 4.62	$ 5.98
Proved plus probable	**$ 7.68**	$ 5.41	$ 3.58	$ 5.03
Costs per boe 6.1 conversion				
Proved	**$ 6.05**	$ 4.43	$ 3.31	$ 4.24
Proved plus probable	**$ 5.02**	$ 4.22	$ 2.64	$ 3.56

Thunder's returns as measured by its recycle ratio improved in 1999 as a result of higher operating netbacks. For every dollar invested, Thunder's average return has been $2.10 over the past three years. Netbacks in 2000 have increased dramatically to in excess of $20.00/boe. With Thunder's low finding and development cost structure, recycle ratios are expected to exceed 3:1 in 2000.

Netbacks and Recycle Ratios	1999	1998	1997	3-Year Average
Operating netbacks	**$ 15.30**	$ 9.80	$ 10.35	$ 11.82
Recycle ratios				
Proved reserves	**1.8**	1.7	2.0	1.8
Proved and probable reserves	**2.0**	1.8	2.4	2.1

The following discussion is management's analysis of Thunder Energy's operating and financial data for 1999 and prior years, as well as estimates of future operating and financial performance based on information currently available.

Clarification of Forward Looking Statements *Statements throughout this annual report that are not historical facts may be considered "forward looking statements." These forward looking statements sometimes include words to the effect that management believes or expects a stated condition or result. All estimates and statements that describe the company's objectives, goals or future plans are forward looking statements. Since forward looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to any number of factors, including such variables as new information regarding recoverable reserves, changes in demand for, and commodity prices of oil and natural gas, legislative, environmental and other regulatory or political changes, competition in areas where the company operates and other factors discussed in this annual report.*

Profitable growth in 1999: Thunder has consistently generated positive returns for shareholders due to its low cost structure. Thunder's strong financial results for 1999 reflect increased production and higher oil and gas prices in the last half of the year. With stronger commodity prices and cash flow in 2000, Thunder has increased its drilling activities and completed a partial buyout of its partner's interests, which will provide a significant platform for growth in 2000.

Financial Results Summary

($ thousands, except per share amounts)	1999	1998	1997
Petroleum and natural gas sales	**$ 15,431**	$ 10,013	$ 5,472
Cash flow from operations	**$ 7,785**	$ 4,537	$ 2,251
Per share – basic	**$ 0.35**	$ 0.28	$ 0.16
– fully diluted	**$ 0.33**	$ 0.25	$ 0.15
Net earnings	**$ 2,437**	$ 1,314	$ 393
Per share – basic	**$ 0.11**	$ 0.08	$ 0.03
– fully diluted	**$ 0.10**	$ 0.08	$ 0.03
Capital expenditures	**$ 21,891**	$ 13,236	$ 19,302
Net long-term debt	**$ 16,933**	$ 13,704	$ 13,754
Net asset value	**$ 68,810**	$ 47,341	$ 38,613
Per share – basic	**$ 2.58**	$ 2.29	$ 2.50
– fully diluted	**$ 2.50**	$ 2.17	$ 2.31
Total capitalization	**$ 70,389**	$ 45,334	$ 45,473

Petroleum and natural gas sales

Petroleum and natural gas sales increased 54% to $15.4 million in 1999 compared with $10.0 million in 1998 and $5.5 million in 1997. The $5.4 million increase in 1999 was attributable to higher natural gas volumes, offset by lower oil volumes and significant price increases for both oil and natural gas. Natural gas continued to be a more significant contributor increasing to 55% of the production base and 59% of total revenues as compared with 48% and 56%, respectively, in 1998.

Petroleum and Natural Gas Sales Summary

($ thousands, except where noted)	1999	1998	1997
Natural gas	**9,061**	5,643	3,311
Crude oil and NGLs	**$ 6,370**	$ 4,370	$ 2,161
Total	**$ 15,431**	$ 10,013	$ 5,472
Production			
Natural gas *(mcf/d)*	**9,347**	7,748	4,580
Crude oil and NGLs *(bbls/d)*	**761**	853	265
Total *(boe/d)*	**1,696**	1,628	723
Gas/oil ratio *(%)*	**55**	48	63
Average selling price			
Natural gas *($/mcf)*	**$ 2.66**	$ 2.00	$ 1.98
Crude oil and NGLs *($/bbl)*	**$ 22.94**	$ 14.57	$ 22.33
Total *($/boe)*	**$ 24.93**	$ 16.85	$ 20.73

Sales Variance Analysis

($ thousands)	1999	1998	1997
Natural gas sales			
Volume increase	**$ 1,166**	$ 2,290	$ 1,990
Price increase	**2,252**	42	291
Net gas sales change	**$ 3,418**	$ 2,332	$ 2,281
Crude oil and NGLs sales			
Volume increase, (decrease)	**$ (489)**	$ 4,792	$ 2,933
Price increase (decrease)	**2,489**	(2,583)	(822)
Net crude oil and NGLs sales change	**$ 2,000**	$ 2,209	$ 2,111
Combined sales change	**$ 5,418**	$ 4,541	$ 4,392

Marketing and hedging activities

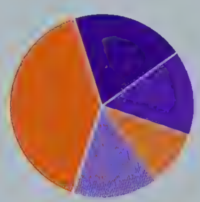
The company markets its natural gas into the Alberta spot market and through aggregators, which sell to major markets in Canada and the United States. Aggregator prices are based on a combination of term and spot markets. Crude oil and natural gas liquids are sold on a spot basis at various delivery points in Alberta. Prices received for crude oil and natural gas liquids are determined by the quality of the crude compared to a benchmark price for light sweet oil. Thunder's composite crude oil is a medium blend averaging approximately 25° API.

Thunder's average price for crude and natural gas liquids was discounted to the Edmonton light posted price by $4.35/bbl ($5.58/bbl in 1998). Of this amount, $0.25 was attributable to foreign exchange losses on U.S. dollar swaps during the year ($0.52/bbl loss in 1998). In 1999, Thunder increased its exposure to the Alberta spot market for natural gas sales with 20% of total sales directed to the spot market, up from 15% in 1998. To capture current pricing upside, this trend will continue. In January 2000, 50% of Thunder's natural gas production was sold on the Alberta spot market.

In conjunction with the acquisition of our partner's interest in 2000, and the resulting increased leverage taken on by the company, Thunder forward sold 65 percent of its future crude oil and 60 percent of its natural gas production. As of March 30th, Thunder had forward sold 800 bbls/d of oil production for the periods ended June 30, 2000, December 31, 2000 and June 30, 2001 at average Edmonton posted prices of $38.00, $35.00 and $32.00/bbl, respectively. For natural gas, Thunder has sold forward 12 mmcf/d at AECO spot prices of $3.90/mcf until November 1, 2000, and 7 mmcf/d at $4.10/mcf from November 1, 2000 until March 1, 2001. These hedges will allow Thunder to pursue a substantial drilling program and, at the same time, make fixed debt repayments until the end of 2000.

In 1998, Thunder entered into a foreign currency swap to fix the U.S. dollar exchange rate at an average of $1.4392 (U.S. $0.695) in the amount of U.S. $300,000 per month. In 1999 the foreign currency swap contracts were extended to December 31, 1999 on a notional cash inflow of U.S. $150,000 per month at Cdn $1.4470 (U.S. $0.69). As at December 31, 1999 all foreign currency exchange swaps expired. Gains and losses from this hedge were recognized in crude oil sales. In 1999 losses from the foreign currency swap totalled $69,609 or $0.25/bbl.

Gas Portfolio



Price Realization

	1999	1998	1997
Natural gas *($/mcf)*			
Benchmark – Average Alberta spot price	$ 2.77	$ 1.93	$ 1.68
Thunder realized price	2.66	2.00	1.98
Premium (discount)	$ (0.11)	$ 0.07	$ 0.30
Crude oil and NGLs *($/bbl)*			
Benchmark – Edmonton 40°API	$ 27.29	$ 20.15	$ 27.64
Thunder realized price	22.94	14.57	22.33
Premium (discount)	$ (4.35)	$ (5.58)	$ (5.31)

Royalties

Thunder's 1999 royalty expenses totalled $2.3 million compared with $891,629 in 1998. As a percentage of revenues, the average royalty rate increased to 14.8% from 8.9% in 1998, but remained constant at the 14.7% reported for 1997. Royalty rates were exceptionally low in 1998 due to higher gas cost allowances for facility costs incurred in 1997. The 2000 royalty rate is expected to remain constant at 15%. Alberta royalty tax credits increased to $366,967 in 1999 from $210,731 in 1998.

Operating expenses

Operating expenses increased to $3.7 million in 1999 from $3.3 million in 1998. On a per boe basis, operating costs increased 6% to $5.92/boe from $5.55/boe in 1998. The year-over-year increase was mainly due to an increase in fixed costs; property taxes, in particular. Gas operating costs decreased to $0.59/mcf compared with $0.66/mcf in 1998. This improvement resulted from increased plant utilization. In 2000, higher volumes of natural gas are expected to further reduce unit operating costs.

General and administrative expenses

Thunder's general and administrative expenses on a per boe basis increased 64% to $1.35/boe from $0.82/boe in 1998. The bulk of the increase was from higher employee costs due to a new stock savings plan and office rent. General and administrative costs for the year totaled $834,558 after a reduction of $1.0 million from overhead recoveries. Thunder receives recoveries for operating producing wells, new drilling and construction activities. Thunder currently operates 99% of its production and anticipates operating 100% of its new wells in 2000. Thunder does not capitalize any general and administrative expenses.

At year-end 1999, the company had 10 full-time employees and seven consultants at its head office. Field staff consisted of five full-time employees and six contract operators. Production increases in 2000 will reduce general and administrative costs on a per unit basis.

General and Administrative Expenses Summary

($ thousands, except where noted)	**1999**	1998	1997
Gross G&A expenses	**$ 1,847**	$ 1,580	$ 1,336
Overhead recoveries	**1,012**	1,094	685
Net G&A expenses	**$ 835**	$ 486	$ 651
Net G&A expenses per boe	**$ 1.35**	$ 0.82	$ 2.47

Interest expense

Interest expense remained stable during the year at $786,805 compared to $764,502 in 1998. Subsequent to year end, Thunder increased its line of credit to $42 million to finance the acquisition of its partner's interest. This credit line is used on a revolving basis and interest is charged at prime. The company has committed to a planned debt reduction of $6 million by year end.

Depletion and depreciation

Depletion and depreciation charges increased to $3.7 million from $2.7 million in 1998. This increase arose due to higher production levels, and higher depletion costs on a per unit basis. Depletion and depreciation increased 29% to $5.96/boe from $4.61/boe in the prior year. At December 31, 1999, Thunder had a ceiling test cushion of approximately $50 million based on year-end wellhead prices of $31.62/bbl for crude oil and NGLs and $2.73/mcf for natural gas.

Income taxes

Total income tax provision increased to $1.7 million from $525,000 in 1998 reflecting higher earnings during the year. The 1999 provision was comprised of $1,658,400 in deferred taxes and $68,500 related to the large corporation tax. This compared with $486,000 in deferred taxes and $39,000 in large corporation tax in 1998. The effective tax rate was 41.4%, up from 28.5% in 1998, and compares reasonably to the expected income tax rate of 44.62%.

Tax Pools

($ thousands at December 31, 1999)		1999
Canadian oil and gas property expenses (COGPE)	$	9,800
Canadian development expenses (CDE)		5,300
Canadian exploration expenses (CEE)		2,000
Undepreciated capital costs (UCC)		15,500
Non-capital losses		2,600
Share issue costs		1,700
Total	$	36,900

Cash flow from operations

Cash flow from operations increased 72% to $7.8 million in 1999 from $4.5 million in 1998, and basic cash flow per share increased 25% to $0.35 from $0.28 in 1998. This increase was primarily due to higher commodity prices which resulted in higher netbacks per barrel of oil equivalent produced.

Cash Flow Summary

	1999	1998	1997
Cash flow from operations *($ thousands)*	$ 7,785	$ 4,537	$ 2,251
Per share basic *($)*	$ 0.35	$ 0.28	$ 0.16
Per share fully diluted *($)*	$ 0.33	$ 0.25	$ 0.15
Cash flow per boe *($)*	$ 12.58	$ 7.70	$ 8.60

Net earnings

Net earnings increased 85% to $2.4 million in 1999 from $1.3 million in 1998 reflecting the combination of higher commodity prices and low cost reserve additions. Shareholders' return on equity averaged 10.5% for the year.

Net Earnings Summary

	1999	1998	1997
Net earnings *($ thousands)*	$ 2,437	$ 1,314	$ 393
Per share basic *($)*	$ 0.11	$ 0.08	$ 0.03
Net earnings per boe *($)*	$ 3.94	$ 2.21	$ 0.95
Return on shareholders' equity *(%)*	10.5	8.6	5.7

Netback Analysis

	Gas *($/mcf)*			Crude Oil *($/bbl)*			$/Boe (@ 10:1)		
	1999	1998	1997	1999	1998	1997	1999	1998	1997
Selling price	$ 2.66	$ 2.00	$ 1.98	$ 22.94	$ 14.57	$ 22.33	$ 24.93	$ 16.85	$ 20.73
Royalties (net of ARTC)	0.43	0.18	0.31	2.26	1.27	2.91	3.71	1.50	3.05
Production expenses	0.59	0.66	0.65	5.94	4.56	6.02	5.92	5.55	6.34
Operating netback	$ 1.64	$ 1.16	$ 1.02	$ 14.74	$ 8.74	$ 13.40	$ 15.30	$ 9.80	11.34
General and administrative							1.35	0.82	2.47
Interest							1.27	1.28	0.29
Large corporation tax expense							0.10	–	–
Cash flow netback from operations							$ 12.58	$ 7.70	$ 8.58
Depletion, depreciation and site restoration							5.96	4.61	5.50
Taxes (deferred)							2.68	0.88	2.15
Net earnings							$ 3.94	$ 2.21	$ 0.93

Capital expenditures

Thunder's total capital expenditures, including $1 million of assets purchased with the issue of shares, amounted to $21.8 million in 1999. During the year $10.9 million was directed to drilling activities, land and seismic; $8.4 million was spent on property acquisitions; and $2.5 million was spent on facilities and equipment costs. Land and seismic costs were significantly higher in 1999 compared to previous years due to expenditures of $2.8 million relating to a joint exploration fund agreement originating in 1998. The larger land base established in 1998/1999 enabled Thunder to develop its large inventory of drilling prospects.

Capital Expenditures Summary

($ thousands)	**1999**	1998	1997
Land and rentals	**$ 3,640**	$ 477	$ 508
Seismic	**665**	105	803
Drilling and completions	**6,642**	5,949	6,243
Facility and equipment	**2,503**	3,825	4,709
Property acquisitions	**8,408**	2,843	6,923
Administrative assets	**33**	37	116
Total	**$ 21,891**	$ 13,236	$ 19,302

Capital efficiency

Thunder's 1999 finding and development costs were $8.75/boe and $7.68/boe on a proved and proved plus probable basis, respectively. The 1999 finding and development costs were higher than Thunder's historical averages ($5.98/boe proved; and $5.03/boe proved plus probable) due to increased land spending and a higher entry cost per boe for the acquisition of Fenn/Big Valley. These investments represented 57% of 1999 spending and are expected to result in lower finding and development costs in future years. Due to higher netbacks in 1999, Thunder's recycle ratio continues to be an acceptable 2.0 times its invested amount. The company's reserve replacement ratio was extremely high at 457% and reserve growth rate was 30% over 1998.

Capital Program Efficiency

($/boe)	**1999**	1998	1997
Operating netback	**$ 15.30**	$ 9.80	$ 10.35
Proved reserves			
Finding and development costs	**$ 8.75**	$ 5.75	$ 4.62
Recycle ratio	**1.8**	1.7	2.0
Proved and probable reserves			
Finding and development costs	**$ 7.68**	$ 5.41	$ 3.58
Recycle ratio	**2.0**	1.8	2.4
Reserves replacement ratio *(%)*	**457**	412	139

Liquidity and capital resources

The company's 1999 capital program was funded with equity, debt and internal cash flow. At December 31, 1999, Thunder's debt and working capital deficit represented 24% of total capitalization.

A total of $9.4 million was raised during 1999 from the issue of 5.8 million common shares at an average price of $1.85/share. In May 1999, warrants that were issued in June 1997 at $1.20/share were converted into common shares providing an additional $1.2 million in equity proceeds. In 1998 a total of 4.6 million shares were issued for gross proceeds of $9.0 million at an average price of $1.98/share.

Subsequent to year end, Thunder has increased its lines of credit to $42 million which, together with internal cash flow, will fund year 2000 capital programs. As a result of Thunder's acquisition of its partner's interests in three of its core properties, debt levels will be higher than under normal operating conditions.

To offset this increased balance sheet leverage, Thunder has forward sold future crude oil and natural gas production to guarantee commodity prices until such time as debt is reduced to a more conventional level. Thunder has committed to a $6 million debt reduction by year-end 2000. Thunder's objective is to maintain its debt to cash flow ratio at or below 2.0 times future cash flows.

Total Capitalization Summary *($ thousands)*	**1999**	1998	1997
Working capital deficiency	**$ 5,108**	$ 3,951	$ 6,792
Long-term debt	**11,825**	9,754	6,962
Deferred income taxes	**1,658**	607	338
Future site restoration and abandonment costs	**311**	176	76
Market value of common shares at December 31	**51,487**	30,846	31,305
Total	**$ 70,389**	$ 45,334	$ 45,473

Forecast for 2000

Thunder's forecast for 2000 includes its recent acquisition of 50% of its partner's interests in three of its four core properties. This acquisition has been structured in two stages; a $10.1 million purchase effective January 1, 2000, and a $15.2 million purchase effective April 1, 2000 price adjusted to January 1. Thunder has adjusted its drilling programs to accommodate the increased expenditures for the acquisition. Thunder has forward sold 800 bbls/d of crude oil production and 12 mmcf/d of natural gas production in the current forecast period at an average price of $36.00/bbl and $3.95/mcf of natural gas. Unhedged production is forecasted to receive industry consensus prices. Total debt at year end 2000 is estimated at $36 million, which is less than 2.0 times future cash flows.

Capital expenditures are expected to total $45 million, of which $25.3 million will be directed towards the acquisition of our partner's interests and $19.7 million towards drilling operations. Thunder expects to drill a total of 40 (33 net) wells in 2000. Cash flow from operations is expected to increase 300% to $24.5 million on a production forecast of 20 mmcf/d of natural gas and 1,200 bbls/d of crude oil and natural gas liquids.

2000 Financial Forecast *($ thousands, except where noted)*	**2000**	1999 Actual
Price assumptions:		
Natural gas prices		
Alberta spot *($/mcf)*	**$ 3.65**	$ 2.77
Thunder wellhead *($/mcf)*	**$ 3.50**	$ 2.66
Oil prices		
WTI *($U.S./bbl)*	**$ 24.50**	$ 15.25
Thunder wellhead *($/bbl)*	**$ 36.20**	$ 22.94
Average daily production		
Natural gas *(mmcf)*	**20**	9.3
Crude oil and NGLs *(bbls)*	**1,200**	761
Capital expenditures	**$ 44,000**	$ 20,413
Cash flow from operations	**$ 24,500**	$ 7,785
Per share (basic)	**$ 0.95**	$ 0.35
Net income	**$ 9,500**	$ 2,437
Per share (basic)	**$ 0.36**	$ 0.11

Cash Flow Sensitivities *(consideration given to hedge program)*	Cash Flow *($ thousands)*	Per Share Basic
Natural gas price change of $0.10/mcf	$ 410	$ 0.02
Natural gas production change of 1 mmcf/d	$ 925	$ 0.04
Crude oil and NGLs price change of $1.00 WTI/bbl	$ 250	$ 0.01
Crude oil and NGLs production change of 100 bbls/d	$ 800	$ 0.03
Interest rate change of 1%	$ 350	$ 0.01

Business risks and risk management

The oil and gas industry is exposed to numerous business risks which can materially affect performance and financial results. Thunder has taken many steps to mitigate these risks.

With respect to commodity prices, Thunder believes that current prices for crude oil are high when compared to historical levels. Thunder has used these higher prices to secure financing for the purchase of its partner's interests in three core areas. Due to a lack of equity funding available to the industry, Thunder has elected to increase its leverage position beyond normal operating conditions. To offset this higher level of financial risk, the company has forward sold 800 bbls/d of crude oil production and 12 mmcf/d of natural gas production at fixed prices. In total this represents approximately 65% of Thunder's current production. This level of hedging will guarantee sufficient cash flow to reduce debt to more conventional levels by year end, while still maintaining a meaningful level of drilling activity. Thunder's objective is to maintain a debt to future cash flow ratio at or below 2.0 times annual cash flow.

To offset fluctuations in commodity prices Thunder strives to be a low cost producer with low finding and development costs, G&A costs and operating expenses. Thunder also focuses on investments that will generate immediate cash flow from new production. Historically, Thunder has maintained recycle ratios, which is a measure of costs to operating netbacks, in excess of 1.7 times proved reserve addition costs.

In reference to exploration and production risks, Thunder operates 100% of its exploration and development programs. This provides control over drilling locations, timing and capital commitments. Thunder maintains a prudent position on the risk/reward spectrum by working in areas with multiple oil and gas targets and where dry hole costs exposures are less than $300,000 per well. The company's exploration and development programs are focused in core areas where it has the experience and history of profitably adding oil and natural gas reserves, and operated facilities provide competitive advantages and ensure new production is brought onstream in a timely manner. Reservoir performance can affect future cash flow projections and reserves evaluations. Thunder is in daily contact with its field staff to track production performance and, to the extent possible, takes immediate corrective action if any adverse situation should arise.

While current market conditions may restrict capital availability to the oil and gas industry, Thunder will maximize its access to capital markets by striving to maintain a strong financial and operational track record. The company will manage market expectations to the greatest degree possible by establishing and meeting reasonable production targets. Over the long term, Thunder expects capital markets to strengthen as a result of continued strength in natural gas prices, attractive returns for oil investments, low interest rates and inflation, and strong economic growth rates.

1999 Quarterly Information

	Q1	Q2	Q3	Q4	1999
Financial *($ thousands, except where noted)*					
Petroleum and natural gas sales	$ 2,400	$ 2,988	$ 4,551	$ 5,492	$ 15,431
Cash flow from operations	$ 1,002	$ 1,388	$ 2,571	$ 2,824	$ 7,785
Per share					
Basic	$ 0.05	$ 0.07	$ 0.12	$ 0.11	$ 0.35
Fully diluted	$ 0.05	$ 0.07	$ 0.11	$ 0.10	$ 0.33
Net income	$ 154	$ 305	$ 1,063	$ 915	$ 2,437
Per share					
Basic	$ 0.01	$ 0.01	$ 0.05	$ 0.04	$ 0.11
Fully diluted	$ 0.01	$ 0.01	$ 0.05	$ 0.03	$ 0.10
Operations					
Daily production					
Natural gas *(mcf)*	7,603	8,707	9,316	11,718	9,347
Crude oil and NGLs *(bbls)*	734	627	837	844	761
Prices					
Natural gas *($/mcf)*	$ 2.03	$ 2.37	$ 2.95	$ 3.03	$ 2.66
Crude oil and NGLs *($/bbl)*	$ 15.25	$ 19.53	$ 26.25	$ 28.72	$ 22.94
Wells drilled					
Gross	4	4	5	15	28
Net	2.1	2	2.5	8.8	15.4
Share trading information					
Volume *(thousands)*	336	824	1,298	855	3,313
High *($)*	$ 1.60	$ 1.95	$ 2.65	$ 2.40	$ 2.65
Low *($)*	$ 1.00	$ 1.30	$ 1.69	$ 1.55	$ 1.00
Close *($)*	$ 1.25	$ 1.75	$ 2.30	$ 2.00	$ 2.00

1998 Quarterly Information

	Q1	Q2	Q3	Q4	1998
Financial *($ thousands, except where noted)*					
Petroleum and natural gas sales	$ 2,396	$ 2,402	$ 2,567	$ 2,648	$ 10,013
Cash flow from operations	$ 1,077	$ 1,064	$ 1,346	$ 1,050	$ 4,537
Per share					
Basic	$ 0.08	$ 0.07	$ 0.08	$ 0.05	$ 0.28
Fully diluted	$ 0.07	$ 0.07	$ 0.07	$ 0.04	$ 0.25
Net income	$ 210	$ 267	$ 414	$ 423	$ 1,314
Per share					
Basic	$ 0.02	$ 0.01	$ 0.03	$ 0.02	$ 0.08
Fully diluted	$ 0.02	$ 0.01	$ 0.02	$ 0.02	$ 0.07
Operations					
Daily production					
Natural gas *(mcf)*	7,037	7,876	7,836	8,229	7,748
Crude oil and NGLs *(bbls)*	872	814	879	847	853
Prices					
Natural gas *($/mcf)*	$ 1.85	$ 2.04	$ 1.79	$ 2.28	$ 2.00
Crude oil and NGLs *($/bbl)*	$ 15.63	$ 12.68	$ 15.83	$ 13.98	$ 14.57
Wells drilled					
Gross	5	16	3	9	33
Net	2.5	8.0	1.5	4.5	16.5
Share trading information					
Volume *(thousands)*	996	873	1,449	649	3,967
High *($)*	$ 2.28	$ 2.44	$ 2.00	$ 1.80	$ 2.44
Low *($)*	$ 1.51	$ 1.69	$ 1.25	$ 1.25	$ 1.25
Close *($)*	$ 2.10	$ 1.90	$ 1.70	$ 1.60	$ 1.60

Management's Report

The accompanying financial statements of Thunder Energy Inc. have been prepared by management in accordance with generally accepted and consistently applied accounting principles. The company's accounting procedures and related systems of internal controls are designed to provide reasonable assurance that its assets are safeguarded and its financial records are reliable. In recognizing that the company is responsible for both the integrity and objectivity of the financial statements, management is satisfied that these financial statements have been prepared accordingly and within reasonable limits of materiality. Further, management is satisfied that the financial information throughout the balance of this annual report is consistent with the information presented in the financial statements.

Ernst & Young LLP have been appointed by the shareholders of Thunder and serve as the company's external auditors. They have examined the financial statements of the company for the year ended December 31, 1999. The Audit Committee has reviewed these statements with management and the auditors, and has reported to the Board of Directors. The Board has approved the financial statements of Thunder which are contained in this annual report.

Douglas A. Dafoe
President and
Chief Executive Officer
February 29, 2000

Jack Peltier
Vice President, Finance and
Chief Financial Officer

Auditors' Report

To the Shareholders of Thunder Energy Inc.

We have audited the consolidated balance sheets of Thunder Energy Inc. as at December 31, 1999 and 1998 and the consolidated statements of operations and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

We conducted our audit in accordance with auditing standards generally accepted in Canada. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the company as at December 31, 1999 and 1998 and the results of its operations and the changes in its cash flows for the years then ended in accordance with accounting principles generally accepted in Canada.

Ernst + Young LLP

Chartered Accountants

Calgary, Canada
February 29, 2000

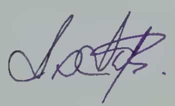
As at December 31

Consolidated Balance Sheets

	1999	1998
***Assets** [note 5]*		
Current		
Accounts receivable	$ 3,132,732	$ 2,021,066
Prepaid expenses	163,811	76,223
	3,296,543	2,097,289
Property and equipment [notes 3 and 4]	48,516,813	31,456,549
	$ 51,813,356	$ 33,553,838
Liabilities and Shareholders' Equity		
Current		
Accounts payable and accrued liabilities	$ 8,404,835	$ 6,048,092
Long-term debt [note 5]	11,825,395	9,753,740
Provision for site restoration	310,761	176,253
Deferred income taxes	1,930,114	607,600
	22,471,105	16,585,685
Shareholders' equity		
Share capital [note 6]	25,178,519	15,241,248
Retained earnings	4,163,732	1,726,905
	29,342,251	16,968,153
	$ 51,813,356	$ 33,553,838

See accompanying notes

On behalf of the Board,



Director

Director

Years ended December 31

Consolidated Statements of Operations and Retained Earnings	1999	1998
Revenue		
Petroleum and natural gas sales	$ 15,431,022	$ 10,013,176
Royalties, net of Alberta Royalty Tax Credit	(2,293,330)	(891,629)
	13,137,692	9,121,547
Expenses		
Operating	3,662,676	3,295,545
General and administrative	834,558	485,897
Interest	786,805	764,502
Depletion, depreciation and site restoration	3,689,926	2,736,785
	8,973,965	7,282,729
Income before taxes	4,163,727	1,838,818
Provision for income taxes [note 7]	1,726,900	525,000
Net income for the year	2,436,827	1,313,818
Retained earnings, beginning of year	1,726,905	413,087
Retained earnings, end of year	$ 4,163,732	$ 1,726,905
Earnings per share [note 8]		
Basic	$ 0.11	$ 0.08
Fully diluted	$ 0.10	$ 0.08

See accompanying notes

Years ended December 31

Consolidated Statements of Cash Flows

	1999	1998
Operating Activities		
Net income for the year	$ 2,436,827	$ 1,313,818
Add items not requiring cash:		
Depletion, depreciation and site restoration	3,689,926	2,736,785
Deferred income taxes	1,658,400	486,000
Cash flow from operations	7,785,153	4,536,603
Changes in non-cash working capital	1,157,489	(2,840,726)
Cash provided by operating activities	8,942,642	1,695,877
Financing Activities		
Issue of common shares for cash, net of costs	9,876,852	8,747,861
Increase in long-term debt	1,593,768	2,791,840
Cash provided by financing activities	11,470,620	11,539,701
Investing Activities		
Expenditures on property and equipment	(13,794,951)	(13,235,578)
Cash portion of corporate acquisition [note 4]	(6,618,311)	–
Cash used in investing activities	(20,413,262)	(13,235,578)
Net change in cash	–	–
Cash, beginning and end of year	$ –	$ –
Cash flow from operations per share [note 8]		
Basic	$ 0.35	$ 0.28
Fully diluted	$ 0.33	$ 0.25

See accompanying notes

1. Description of Business

Thunder Energy Inc. (the "company") was incorporated under the laws of the Province of Alberta on October 17, 1995. The company's primary business is the acquisition of, and the exploration for and development and production of crude oil and natural gas in Western Canada.

2. Significant Accounting Policies

The consolidated financial statements include the accounts of the company and its wholly owned subsidiaries.

The consolidated financial statements have been prepared in accordance with generally accepted accounting principles which, in management's opinion, have been properly prepared within reasonable limits of materiality and within the framework of the accounting policies summarized below.

Property and equipment

Petroleum and natural gas properties and gas plants and related facilities

The company follows the full cost method of accounting whereby all costs associated with the acquisition of and exploration for and development of petroleum and natural gas reserves, whether productive or unproductive, are capitalized in a Canadian cost centre and charged to income as set out below. Such costs include lease acquisition, drilling, geological and geophysical costs and overhead expenses directly related to exploration and development activities. No general and administrative costs have been capitalized during the years ended December 31, 1999 and 1998.

Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion of 20% or more.

Depletion of petroleum and natural gas properties is provided on accumulated costs using the unit of production method based on estimated proven petroleum and natural gas reserves, before royalties, as determined by independent engineers. For purposes of the depletion calculation, proven petroleum and natural gas reserves are converted to a common unit of measure on the basis of one barrel of oil or liquids being equal to six mcf of natural gas. Costs of acquiring and evaluating unproven properties are excluded from depletion calculations until it is determined whether or not proven reserves are attributable to the properties or impairment occurs. Depreciation of gas plants and related facilities is calculated in a straight line basis over a fifteen year term.

The net carrying value of the company's petroleum and natural gas properties and gas plants and related facilities is limited to an ultimate recoverable amount. This amount is the aggregate of estimated future net revenues from proven reserves and the costs of unproven properties, net of impairment allowances, less future estimated production costs, general and administrative costs, financing costs, site restoration and abandonment costs, and income taxes. Future net revenues are estimated using prices and costs without escalation or discounting, and the income tax and Alberta Royalty Tax Credit legislation in effect at the year ends.

Provision for site restoration

Estimated future costs relating to abandonment and site restoration of petroleum and natural gas properties and gas plants and related facilities are provided for over the life of proven reserves on a unit of production basis. The annual provision is accounted for as part of depletion, depreciation and site restoration expense and actual expenditures are charged to the accumulated provision account as incurred. Costs, net of expected recoveries, are estimated based upon current legislation, costs, technology and industry standards.

Office equipment

The company records office equipment at cost and provides depreciation on the declining balance method at rates varying from 20% to 100% per annum which is designed to amortize the cost of the assets over their estimated useful lives.

Measurement uncertainty

The amounts recorded for depletion and depreciation of property and equipment and the provision for site restoration costs are based on estimates. The ceiling test calculation is based on estimates of proven reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the consolidated financial statements of changes in such estimates in future periods could be significant.

Joint operations

Substantially all petroleum and natural gas activities are conducted jointly with others. These consolidated financial statements reflect only the company's proportionate interest in such activities.

Income taxes

The company follows the deferral method of tax accounting under which the income tax provision is based on the earnings reported in the accounts. Under this method, the company provides for deferred income taxes to the extent that income taxes otherwise payable are reduced by exploration and development costs and capital cost allowances in excess of the depletion and depreciation provisions recorded in the accounts.

Flow through shares

A portion of the company's exploration and development activities is financed through proceeds received from the issue of flow through shares. Under the terms of the flow through share issues, the tax attributes of the related expenditures are renounced to the share subscribers. To recognize the foregone tax benefits, the carrying value of the company's oil and gas properties and the flow through shares issued are recorded net of the tax benefit of the renouncements when the qualifying expenditures occur.

Financial instruments

Financial instruments of the company consist mainly of accounts receivable, accounts payable and accrued liabilities, long-term debt and swaps relating to foreign currency exchange. As at December 31, 1999 and 1998, there are no significant differences between the carrying amounts of these instruments on the balance sheet and their estimated fair values.

Foreign exchange hedges are used by the company to manage its exposure to fluctuations in the U.S. dollar exchange rate. Gains and losses relating to foreign currency exchange swaps are recognized as part of petroleum and natural gas sales when realized. During the year ended December 31, 1998, the company entered into foreign currency swap contracts with a Canadian chartered bank to fix the U.S. dollar exchange rate at an average of Cdn $1.4392 (U.S. $0.695) on a notional cash inflow of U.S. $300,000 per month. In 1999, the foreign currency swap contracts were extended to December 31, 1999 on a notional cash inflow of U.S. $150,000 per month at Cdn $1.4470 (U.S. $0.691). As at December 31, 1999, all foreign currency swaps expired.

3. Property and Equipment

1999

	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	$ 37,465,189	$ 5,126,417	$ 32,338,772
Gas plants and related facilities	18,728,467	2,629,654	16,098,813
Office equipment	225,362	146,134	79,228
	$ 56,419,018	$ 7,902,205	$ 48,516,813

1998

	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	$ 21,491,930	$ 2,711,419	$ 18,780,511
Gas plants and related facilities	14,119,124	1,504,225	12,614,899
Office equipment	192,282	131,143	61,139
	$ 35,803,336	$ 4,346,787	$ 31,456,549

At December 31, 1999 costs of $3,800,000 related to unproven properties have been excluded from the depletion and ceiling test calculations (1998 – $3,800,695).

4. Business Acquisition

On June 17, 1999, the company acquired all of the issued and outstanding shares of 545328 Alberta Ltd., K.B.M. Energy Ltd., 603522 Alberta Ltd., Berger Enterprises Ltd., 615461 Alberta Ltd. and MIS Consulting (1988) Ltd., whose sole assets were joint venture interests in the oil and gas assets of PAZ Energy Ltd., ("PAZ") in exchange for 606,060 common shares of the company valued at $1,000,000 and $6,618,311 in cash.

The acquisition has been accounted for by the purchase method, whereby the fair value of the purchase consideration was allocated to the fair value of the net assets of PAZ. Accrued costs of the acquisition are included in the property and equipment acquired. The purchase price was allocated as follows:

Purchase price

Cash	$ 6,618,311
Common shares	1,000,000
	$ 7,618,311

Allocated to

Property and equipment acquired	$ 8,096,198
Long-term debt assumed	(477,887)
	$ 7,618,311

5. Long-Term Debt

The company has a $17,000,000 credit facility consisting of a revolving demand loan with a Canadian chartered bank that bears interest at the bank's prime rate. The company has pledged all its assets as collateral for loans under the facility.

At December 31, 1999, the effective interest rate on the debt outstanding was 6.21% (1998 – 6.09%). Interest paid during the years ended December 31, 1999 and 1998 approximates interest expense in each year.

While the credit facility is demand in nature, the bank has stated that it is not its intention to call for repayment before December 31, 2000 provided there is no adverse change in the financial position of the company. Accordingly, the loan is classified as long term.

In February 2000, the company increased its credit facility to $30,000,000. The terms of and security required under the new facility remain the same.

6. Share Capital

Authorized

Unlimited number of common shares

Unlimited number of preferred shares issuable in series

Issued	*Number of Shares*	
Balance of common shares, December 31, 1997	***14,360,000***	***$ 7,135,244***
Issued on conversion of Special Warrants (a)	*2,500,000*	*4,797,127*
Issued for cash on private placements (b)	*2,052,500*	*3,956,801*
Issue for cash on exercise of stock options	*366,667*	*209,833*
Tax benefits renounced (f)	–	*(857,757)*
Balance of common shares, December 31, 1998	***19,279,167***	***15,241,248***
Common shares issued on conversion of warrants (c)	*1,025,000*	*1,230,000*
Common shares issued to acquire PAZ (note 4)	*606,060*	*1,000,000*
Special Warrants issued for cash (d)	*3,333,333*	*5,287,624*
Common shares issued for cash (e)	*1,500,000*	*3,695,114*
Tax benefits renounced (f)	–	*(1,275,467)*
Balance of common shares December 31, 1999	***25,743,560***	***$ 25,178,519***

(a) In May 1998, the company issued 2,500,000 Special Warrants for gross proceeds of $5,000,000. Issue costs totaled $363,773 and have been recorded net of the associated tax benefit of $160,900. In June, 1998 the Special Warrants were converted into common shares.

(b) During 1998, the company issued 2,052,500 flow through common shares for gross proceeds of $4,025,000. Aggregate issue costs totaled $123,199 and have been recorded net of the associated tax benefit of $55,000.

(c) In May 1999, 1,025,000 warrants were converted into 1,025,000 common shares of the company at a price of $1.20 per share for gross proceeds of $1,230,000.

(d) In June 1999, the company issued 3,333,333 Special Warrants for gross proceeds of $5,500,000. Issue costs totaled $369,537 and have been recorded net of the associated tax benefit of $157,161. The Special Warrants were converted into common shares on July 22, 1999.

(e) In October 1999, the company issued 1,500,000 flow through common shares for gross proceeds of $3,900,000. Issue costs totaled $383,611 and have been recorded net of the associated tax benefit of $178,725.

(f) In accordance with the terms of its flow through share offerings, and pursuant to certain provisions of the *Income Tax Act* (Canada), the company is committed to renounce, for income tax purposes, exploration and development expenditures incurred to holders of its flow through shares. During the year ended December 31, 1999, the company renounced $2,858,791 of expenditures (1998 – $1,923,221). At December 31, 1999, the company is required to incur eligible exploration and development expenditures of $3,142,988.

The carrying values of property and equipment and share capital have been reduced by $1,275,467 at December 31, 1999 to reflect the tax benefits of the expenditures renounced (1998 – $857,757).

Stock based compensation

The company has established a stock option plan whereby options may be granted to the company's directors, officers and employees for up to 2,500,000 common shares. The exercise price of each option equals the market price of the company's stock on the date of the grant. An option's maximum term is five years and the options vest equally over three years beginning at the date the option is granted. No compensation expense is recognized for the plan when stock options are issued or exercised. The following is a continuity of stock options outstanding for which shares have been reserved:

	1999		1998	
	Options	Weighted-Average Exercise Price	Options	Weighted-Average Exercise Price
Opening	1,450,000	$ 1.30	1,350,000	$ 1.04
Granted	370,000	$ 1.64	475,000	$ 1.75
Exercised	–	–	(366,667)	$ (0.57)
Cancelled	(10,000)	$ (1.68)	(8,333)	$ (1.40)
Closing	1,810,000	$ 1.37	1,450,000	$ 1.30

At December 31, 1999 1,021,275 stock options (1998 – 571,666) were exercisable at a weighted average exercise price of $1.12 per share (1998 – $0.96 per share).

7. *Income Taxes*

Income taxes recorded on the consolidated statements of operations and retained earnings differ from the tax calculated by applying the combined Canadian corporate federal and provincial income tax rate to income before taxes as follows:

	1999	1998
Computed income tax expense at 44.62%	$ 1,857,900	$ 820,500
Add (deduct) income tax effect of:		
Non-deductible crown charges, net of ARTC	471,200	186,500
Resource allowance	(980,000)	(542,800)
Non-deductible portion of depletion	358,000	71,300
Other	(48,700)	(49,500)
Deferred income tax expense	1,658,400	486,000
Large corporation tax expense	68,500	39,000
Provision for income taxes	$ 1,726,900	$ 525,000

As at December 31, 1999, the company has non-capital losses of approximately $2,600,000 available to reduce future years' taxable income (1998 – $2,800,000). The non-capital losses expire as follows: 2004 – $994,100; 2005 – $1,305,900.

In addition, the company has exploration and development costs, undepreciated capital costs and unamortized share issue costs available for deduction against future taxable income of approximately $34,300,000 (1998 – $23,200,000).

Cash taxes paid in the year ended December 31, 1999 were $41,260 (1998 – $11,100).

8. *Per Share Amounts*

The calculation of basic and fully diluted earnings per share and cash flow from operations per share is based on the weighted average number of common shares outstanding during the year ended December 31, 1999 of 21,965,885 (1998 – 16,186,888). The fully diluted weighted average number of shares outstanding during the year ended December 31, 1999 is 24,438,059 (1998 – 18,903,440).

9. *Comparative Figures*

In 1999, the company adopted, on a retroactive basis, the requirements of the Canadian Institute of Chartered Accountants as they relate to the presentation of the cash flow statement.

10. *Subsequent Event*

Effective January 1, 2000, the company acquired a 10% working interest in various oil and gas properties from an existing joint venture partner for an estimated total cost, before adjustments of $10.1 million. In addition, the company has an option to acquire the remaining working interest in the same oil and gas properties on or before December 31, 2000. If the option is exercised prior to May 1, 2000 the purchase price will be determined under the same terms, conditions and effective date as the initial 10% working interest acquisition. If the option is exercised after May 1, 2000, the purchase price and effective date will be re-negotiated.

Four-Year Review

Financial

Years ended December 31 *($ thousands, except where noted)*	1999	1998	1997	1996
Petroleum and natural gas sales	**$ 15,431**	$ 10,013	$ 5,472	$ 1,080
Cash flow from operations	**$ 7,785**	$ 4,537	$ 2,251	$ 347
Per share – basic *($)*	**$ 0.35**	$ 0.28	$ 0.16	$ 0.11
– fully diluted *($)*	**$ 0.33**	$ 0.25	$ 0.15	$ 0.11
Net earnings	**$ 2,437**	$ 1,314	$ 393	$ 18
Per share – basic *($)*	**$ 0.11**	$ 0.08	$ 0.03	$ 0.01
– fully diluted *($)*	**$ 0.10**	$ 0.08	$ 0.03	$ 0.01
Return on equity *(%)*	**10.5**	8.6	5.7	0.6
Capital expenditures	**$ 21,891**	$ 13,236	$ 19,302	$ 5,248
As at December 31				
Total assets	**$ 51,813**	$ 33,554	$ 25,326	$ 8,723
Net long-term debt	**$ 16,933**	$ 13,704	$ 13,754	$ (1,404)
Shareholders' equity	**$ 29,342**	$ 16,968	$ 7,548	$ 6,194
Common shares outstanding *(thousands)*				
Basic	**25,744**	19,279	14,360	12,310
Fully diluted	**27,544**	21,744	16,735	13,325
Weighted average – basic	**21,966**	16,187	13,506	3,183
– fully diluted	**24,408**	18,903	15,270	4,198
Share price *($)*				
High	**$ 2.65**	$ 2.44	$ 3.25	$ 1.15
Low	**$ 1.00**	$ 1.25	$ 0.90	$ 0.90
Close	**$ 2.00**	$ 1.60	$ 2.18	$ 0.90
Volumes *(thousands)*	**3,313**	3,967	10,340	221

Operations

Years ended December 31	1999	1998	1997	1996
Average daily production				
Natural gas *(mcf)*	**9,347**	7,748	4,580	1,568
Crude oil and NGLs *(bbls)*	**761**	853	265	4
Barrels of oil equivalent	**1,696**	1,628	723	161
Average product prices				
Natural gas *($/mcf)*	**$ 2.66**	$ 2.00	$ 1.98	$ 1.81
Crude oil and NGLs *($/bbl)*	**$ 22.94**	$ 14.57	$ 22.33	$ 30.77
Wells drilled				
Gross	**28**	33.0	36.0	–
Net	**15.4**	16.5	16.0	–
Success rate *(%)*	**93**	91	93	–
As at December 31				
Reserves – proved plus probable				
Natural gas *(bcf)*	**64.2**	45.2	37.6	10.4
Crude oil and NGLs *(mbbls)*	**3,852**	3,548	2,461	94
Barrels of oil equivalent *(mboe)*	**10,272**	8,068	6,221	1,134
Net asset value	**$ 68,810**	$ 47,341	$ 38,613	$ 11,785
Per share – basic *($)*	**$ 2.58**	$ 2.29	$ 2.50	$ 0.89
– fully diluted *($)*	**$ 2.50**	$ 2.17	$ 2.31	$ 0.88

Corporate Information

Directors and Officers

Douglas A. Dafoe, C.A.★†
President and Chief Executive Officer
Thunder Energy Inc.

David L. Barlow, P.Geol.★†
Vice President, Exploration
Thunder Energy Inc.

Colin D. Boyer, P.Eng.(1)(2)(3)★
President
Boyer Petroleum Engineering Ltd.

Jack Peltier(1)(2)(3)★†
President
Ipperwash Resources Ltd.

James M. Pasieka(1)(2)(3)★
Barrister & Solicitor
Vice President
Cavendish Investing Ltd.

Terry S. Meek, P.Eng.†
Vice President, Engineering
Thunder Energy Inc.

Murray Desrosiers
Corporate Secretary,
Gowling, Strathy & Henderson
Barristers and Solicitors

(1) Audit Committee
(2) Compensation Committee
(3) Reserve Evaluation Committee
★ Director
† Officer

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Auditors

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Calgary, Alberta

Stock Listing

The Toronto Stock Exchange
Symbol: THY

Bankers

Royal Bank
Calgary, Alberta

Transfer Agent & Registrar

The Trust Company of Bank of Montreal
Calgary, Alberta

Legal Counsel

Gowling, Strathy & Henderson
Calgary, Alberta

Abbreviations

bbl(s)	*barrel(s)*
mbbls	*thousand barrels*
mmbbls	*million barrels*
mcf	*thousand cubic feet*
mmcf	*million cubic feet*
bcf	*billion cubic feet*
boe	*barrel of oil equivalent (10 mcf = 1 bbl)*
mboe	*thousand boe*
/d	*per day*
ARTC	*Alberta Royalty Tax Credit*
NGLs	*Natural gas liquids*
WTI	*West Texas Intermediate*

Notice of Annual Meeting

Shareholders and guests are invited to attend the Annual Meeting to be held on Wednesday, May 31, 2000 at 3:00 p.m. in the McMurray Room of The Calgary Petroleum Club, 319 - 5th Avenue S.W., Calgary, Alberta.

For current information, visit us at our website:
www.thunderenergy.com

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